Update

Forecast of Activity in British Columbia For Liquified Natural Gas, Extraction of Natural Gas Liquids, and Petrochemical Developments

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Update

Forecast of Activity in British Columbia For Liquified Natural Gas, Extraction of Natural Gas Liquids, and Petrochemical Developments

Prepared by Confer Consulting Ltd.

June, 1984

1. Summary

In 1983, B. C. Hydro commissioned Confer Consulting Ltd. to prepare a forecast of activity in British Columbia for Liquefied Natural Gas (LNG), extraction of Natural Gas Liquids (NGL's) and Petrochemical developments. B. C. Hydro has asked Confer Consulting Ltd. to update its 1983 forecast for use in the 1984 Load Forecast.

In the 1983 report, the probability of the LNG plant proceeding was estimated to be below 50% and a recommendation was made to not include the project in B. C. Hydro's probable load forecast. With respect to NGL extraction, the 1983 study forecast a new plant with inlet capacity of 9000 10^3m^3 per day to commence operation in 1987. For petrochemicals, the report estimated that a new world scale methanol facility would start production in 1990, but no new ammonia or ethylene and derivative facilities would be constructed during the forecast period.

For the update, Confer has reviewed the marketing opportunities for LNG, NGL's and petrochemicals from B. C., reviewed pertinent events which occurred during the past year and discussed project status with proponents and industry observers. The conclusions of the update are:

1. The Western LNG project has a sales agreement with five Japanese utilities to deliver 2.9 Mt (160.1 PJ) per year of LNG starting in early 1989. The project has received an Energy Removal Certificate from the British Columbia government. Approvals from the Alberta and federal governments are postponed until project gas supply and price are contracted. Failure to secure gas supply, government approvals and Dome debt rescheduling by October, 1984 would probably cause the sales agreement to be cancelled.

2. The project revenue has increased since the 1983 study because of modestly higher volume, lower foreign exchange rate and changes in the computation of the Canada/U.S. border gas price. The project costs have decreased significantly because of project restructuring, lower inflation and better cost effectiveness. Returns to the natural gas producer are higher in the 1984 study compared to the 1983 estimate, but still average below the Alberta Border Price (ABP) for about the first ten years of production.

3. Contract terms and especially the price of natural gas to producers are proving difficult to complete. In addition to making satisfactory arrangements with producers, the project requires several new equity partners. No clear indication of new partner participation has been received to date, but negotiations continue.

4. Alberta government policy does not currently contemplate exports of natural gas at prices below the ABP. Although this policy may be softened in the medium term, the project economics are sensitive to many factors and no reasonable assurance can be given that the residual value for natural gas can be equal to or exceed ABP during the first ten years of project operation.

5. As a result of these conclusions, the relatively low probability of the project proceeding is not changed from the 1983 estimate. The project should not be included in B. C. Hydro's 1984 probable forecast of electric energy requirements, but, as in 1983, the band of electric energy requirements around the probable case could accommodate a load like the LNG facility.

6. A Natural Gas Liquids (NGL) extraction facility will become operational near Taylor, B. C. in late 1985. The project which is designed to make a "deep cut" and extract substantial NGL volumes is sponsored by Westcoast Transmission Company Limited (WTCL) and will recover ethane, propane, butanes and pentanes plus. It will likely use electric drive and have an annual electric energy requirement of 150 GW.h.

7. For petrochemicals, no ethylene or derivative plants are forecast.

   Methanol fuel use, growing commitment of current Canadian methanol supply to other markets and B. C.'s new natural gas petrochemical pricing policy allowing producers to negotiate prices directly with plant developers could cause demand for a new methanol facility in the 1990 to 1995 period.

   Ammonia demand will grow modestly and B. C. will have to look to increasing demand in the Pacific Basin for market opportunities. However, a B. C. ammonia plant would have relatively high construction and gas costs, and may not be competitive with low gas costs at or near new markets. This makes B. C. marginal supplier to the Pacific Rim ammonia market.

   Again, the new B. C. natural gas petrochemical pricing policy could have favourable impact on an ammonia project in the early 1990's, but no plant should be included in the B. C. Hydro probable case until better indications of negotiated gas prices to petrochemical plants are known.

2. Liquefied Natural Gas (LNG)

2.1 Introduction

Modest progress has been made on the Western LNG project approval during 1983. Hearings before the British Columbia Utilities Commission (BCUC) were completed, and an Energy Removal Certificate was issued by the British Columbia government in April, 1984. Hearings were also held before the National Energy Board (NEB) for permits to construct and operate the facilities. The second phase of these hearings, which will deal with financial and business arrangements, has not been held and will remain postponed until natural gas supply and pricing arrangements have been made. The NEB has extended its conditional approval deadline for natural gas exports from January 1984 to January 1985. Negotiations for natural gas supply with Alberta and British Columbia governments and natural gas producers have continued, but no firm resolution has been completed.

2.2 LNG Markets and Supply

The analysis of LNG markets and supply developed in the 1983 study has not changed significantly. Japan is still the major focal point of Pacific Basin LNG demand, with electricity generation the main LNG use in Japan. A new round of LNG expansion is currently near completion, and shipments commence in 1983 and 1984. Table 1 presents an updated LNG supply and demand balance for Japan. Small LNG supply changes since 1983 result from more recent plant capacity information.

It should be noted that the LNG plants shown on Table 1 are dedicated to specific Japanese utilities under long term contracts. In each case, the price of LNG is related to movements in various crude oil prices.

During 1983, the South Korean electric utility (Kepco) signed a contract for LNG to commence in 1986 at 2 Mt* per year. Initial volumes under the contract may be 1 Mt per year, but could rise to 3 Mt per year in the 1990's. This contract is significant because it is the first Pacific Basin LNG demand outside Japan. Supply will be from Indonesia where an additional production train will be added at the existing Arun plant. The contract price of LNG is based on 90% parity with a basket of crude oil prices. This is lower than most LNG prices in Japan which are based on full parity value with crude oil. The Korean LNG price is lower than the Western LNG project price which has a more complicated set of pricing variables but which has a slight premium of LNG price over FOB crude prices.

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* 1 Mt is 1 million metric tonnes.

TABLE 1

JAPAN

Supply and Demand of LNG

SUPPLY
Mt per year

Location:	Quantity	
Operating:		
Alaska-Kenai	0.96	
Brunei	5.14	
Abu Dhabi	2.05	
Indonesia-Arun	5.30	
-Badak	4.00	17.45
Under Construction: (first year of operation)[a]		
Indonesia - Arun (1984)	3.3	
- Badak (1983)	4.0	
Malaysia - Bintulu (1983)	6.0	13.3
Total Supply		30.75

[a] Plant capacity shown is at full operation which may not be achieved for some years as market builds.

DEMAND
Mt per year

	1981	1985	1990	1995
Electricity generation	13.2	19-20	26-28	31-33
Other Use	3.7	5-6	6-7	7-7
Total	16.9	24-26	32-35	38-41

Discussion with Canadian LNG industry observers indicate no other LNG demand outside Japan is expected in the Pacific Basin during the 1980's, but some opportunity may develop during the 1990's. This assessment is based on no apparent market need for LNG before 1990, and the difficulty of getting a new project completed and on-stream by 1990.

Table 1 shows that Japan LNG demand will be about 32 to 35 Mt in 1990. This will require new ship terminal and electric generation facilities in Japan, and construction has begun at some locations, although most are still in the planning stage. Supply of LNG to Japan from existing facilities totals some 30 to 31 Mt per year, and includes capacity which has a demonstrated record of operating in excess of design capacity. With only existing facilities, a supply shortfall of 1 to 5 Mt could exist in 1990.

The Japanese utilities have several options to meet this shortfall. One is to install additional production trains at existing facilities. This could be done at Indonesian and possibly the Malaysian projects. Because Indonesia would already supply over 50% of Japan's LNG, a location outside Indonesia may be preferred to maintain satisfactory diversity of supply.

New projects could also supply the LNG shortfall in 1990. Alternatives include projects (with total annual LNG output in brackets) in Western Canada (2.9 Mt), Northwest Australian Shelf (6 Mt), Thailand, Sakhalin Island (3 Mt) and another Malaysian project. The Western LNG project sponsored by Dome Petroleum Limited is now scheduled to commence operation in late 1988, and it would fit nicely into the projected Japanese LNG shortfall for 1990. Most of the other LNG supply projects could also fit into this time frame.

2.4 The Western LNG Project

The Japanese customers for LNG from the Western LNG Project remain unchanged from 1983, with Chubu Electric the key utility because it will take 1.6 Mt per year of LNG, or 55% of the output. The project's partners have been expanded to include Union Oil Company of Canada Limited with a 10% interest. NIC Resources Inc. (NIC), a subsidiary of the Japanese trading company Nissho-Iwai, still retains 10% of the project, and Domes's share dropped from 90% to 80%.

Project facilities and electric energy requirements are essentially the same as discussed in the 1983 report. The only significant change is the use of four instead of five LNG tankers due to larger containment structures.

2.4.1 Project Economics

The project revenue from LNG sales in Japan is generally higher in the 1984 study compared to the 1983 estimate. This is due to several factors, including a change to use average U.S. crude oil

price to set the U.S./Canada Border Reference price for natural gas (rather than the Montreal import price as in 1983 study), faster volume build-up during initial years of operation, and a lower foreign exchange rate between Canadian and U.S. currencies. More detailed discussion of revenue occurs later in this report.

Major changes have occurred since the 1983 study in the structure of the project and its costs. With respect to the structure, the major change is in the method of determining project returns to project sponsors. As originally proposed, the project partners would receive a substantial marketing fee (based on CIF revenues) and a return on "deemed" equity in the LNG plant. These two components became large over the course of the project's life and were mentioned by several observers, including the NEB, for consideration in cost reductions to allow more money for natural gas producers.

After the 1983 study was complete, a "minimum" project cost structure was proposed. It includes a small marketing fee and only debt service costs at the LNG plant. All ship and pipeline transportation costs remain on cost of service arrangements. The change in structure has the effect of lowering the overall project cost components and raising the residual natural gas value.

To compensate for no return at the LNG plant and for the obligations associated with ship, plant and pipeline financing, the project partners now propose to participate in the residual natural gas value at the inlet point of gas supply which has been established to be at Station 3 on Westcoast Transmission Company Limited's (WTCL) mainline. The participation involves several stages:

- a guaranteed price of C $1.70 per GJ to the gas producer, adjusted up or down with the CIF LNG price. If the actual price in any year is below this minimum price, the deficiency is made up, without interest, at the first time the actual price exceeds the minimum price and until the producer has received the minimum price for all production to date;

- once the gas producer has received the minimum price the project partners receive all incremental revenue to a maximum of 30% of total gas value. The project partners also receive any deficiency in their 30% share, without interest; and

- after both gas producers and project partners have received their shares, including any deficiencies, they share residual natural gas value on a 70/30 basis, respectively.

Another structural change in the project is to maximize the supply of natural gas during summer months. The LNG must be delivered at regular intervals in Japan, but, with LNG storage at the plant and with natural gas storage, large portions of gas could be supplied during the summer off-peak months. This has the effect of filling the "valleys" of gas supply to heating loads in North America, and would be attractive to producers with production facilities operating at under utilized rates during summer months.

In addition to structural changes in the project, the cost estimates for construction and operation of the project facilities have declined.

For the marine component, Dome has received actual firm bids from several shipping interests during early 1984. Evaluation of these bids shows no increase in marine shipping costs between 1982 and 1984. Lower estimates of shipping costs are due to lower inflation, better financial terms and, most significantly, to the use of four larger tankers instead of five smaller tankers.

At the time of the 1983 study, Dome was initiating a review of construction and operating costs for the LNG plant and gas pipeline. The review was completed late in 1983 and the results now form the basis for the 1984 analysis. A comparison of the economic parameters and project costs used by Dome and Confer/B. C. Hydro in 1983 and 1984 is shown on Table 2.

In the case of capital costs, Dome explains the decline between 1983 and 1984 as a combination of better engineering, lower contingencies and better cost effectiveness. Confer reviewed Dome's cost estimates with industry officials familiar with LNG plant and gas pipeline costs. Most are satisfied the current cost estimates for the LNG plant are reasonable. The Dome capital cost estimates for the natural gas pipeline from WTCL Station 3 to Prince Rupert appeared low to some observers. Confer asked WTCL for their most recent cost estimate and it is about one-third higher than the Dome estimate. The WTCL estimate is used in this study.

For operating costs, the decline between 1983 and 1984 is explained by a combination of lower inflation, better municipal tax estimates, and more detailed operating cost review. Dome's estimate of pipeline operating costs have been increased by the same ratio as capital cost increases.

TABLE 2

COMPARISON OF ECONOMIC PARAMETERS, CAPITAL AND OPERATING COSTS OF LNG PLANT AND GAS PIPELINE

	1983		1984	
	WLNG[a]	Confer/BCH	WLNG	Confer/BCH
Economic Parameters				
- Canadian Inflation[b] (%/yr)	8-9	5-10	5-6	5-6
- Capital Cost Escalation (%/yr)	10-11	8-10	5-7	5-7
- Operating Cost Escalation (%/yr)	10-11	6-8	5-7	5-7
- Long-Term Debt Cost[c] (%/yr)	13	12-13	12-11	11.5-13.5
Project Costs[d] (millions $)				
- LNG Plant Capital Cost - 1983 $	1450	1390	1050	1050
- LNG Plant Operating Cost (1990) - current $	153.2	147	101	101
- Pipeline Capital Cost - 1983 $	665	640	438	596
- Pipeline Operating Cost (1990) - current $	30.9	30	20.5	27.9

a Western LNG project.
b Range over forecast period.
c For LNG plant, Japanese financing at 9.75% is assumed. Other long-term financing at interest rates shown.
d The costs shown are from several sources and may not be directly comparable. They do, however, provide direction to cost movements between 1983 and 1984 study.

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The results of the 1983 study showed low residual natural gas values. They were based on the 1983 B. C. Hydro crude oil and natural gas price forecast, B. C. Hydro economic parameters, a project cost structure with high front end costs, and high inflation and real cost adjustments to 1981 cost estimates. Since that time, project economics have been improved by higher revenue and by lower costs from both structural and estimation changes. Table 3 shows the results of the 1984 study, and Table 4 compares results of the 1983 and 1984 studies.

TABLE 3

B. C. HYDRO

WESTERN LNG PROJECT[a]
(millions $ unless otherwise noted)

Year	CIF Volume PJ	CIF Revenue US$	Cost Marine US$	Cost Plant C$	Cost Pipeline C$	Station 3 Volume PJ	Station 3 Revenue C$	Station 3 Total Price C$/GJ	Station 3 Producer Price C$/GJ	Station 3 Developer Price C$/GJ	ABP C$/GJ
1988	104.9	602	80	157	100	110.3	392	3.55	2.49	1.07	2.76
1989	151.8	923	132	305	146	159.7	520	3.25	2.28	0.98	2.87
1990	160.1	1,032	137	307	183	168.5	609	3.61	2.53	1.08	3.08
1991	160.1	1,094	148	348	176	168.5	636	3.78	2.64	1.13	3.29
1992	160.1	1,160	149	400	177	168.6	662	3.93	2.75	1.18	3.54
1993	160.1	1,229	152	389	174	168.6	758	4.50	3.15	1.35	3.78
1994	160.1	1,303	152	377	220	168.7	813	4.82	3.37	1.45	4.01
1995	160.1	1,381	158	366	216	168.7	909	5.39	3.77	1.62	4.26
1996	160.1	1,464	159	356	212	168.8	1,024	6.07	4.25	1.82	4.53
1997	160.1	1,552	164	346	208	168.8	1,139	6.75	4.72	2.02	4.80
1988-1987	1,537.5	11,740	1,431	3,351	1,812	1,619.2	7,462	4.61	3.23	1.38	3.69
1998	160.1	1,645	172	263	195	168.8	1,339	7.93	5.55	2.38	5.11
1999	160.1	1,744	156	164	189	168.9	1,583	9.37	6.56	2.81	5.45
2000	160.1	1,849	145	173	186	168.9	1,718	10.17	7.12	3.05	5.82
2001	160.1	1,960	149	183	184	169.0	1,842	10.90	7.63	3.27	6.18
2002	160.1	2,077	153	193	182	169.0	1,972	11.67	8.17	3.50	6.58
1998-2002	800.5	9,275	775	976	936	844.6	8,454	10.01	7.01	3.00	5.83
1988-2002	2,338.0	2,206	2,206	4,327	2,748	2,463.8	15,916	6.46	4.52	1.94	4.40

[a] Based on BCH computer run on 14 May 1984.

TABLE 4

COMPARISON OF KEY PARAMETERS BETWEEN
1983 AND 1984 STUDY RESULTS

Period/Variable	CIF Volume PJ	CIF Revenue millions US$	FX Rate C$/US$	Total Cost millions C$	Station 3 Total Revenue millions C$	Station 3 Producer Price C$/GJ	Station 3 Developer Price C$/GJ	ABP[f] C$/GJ
1990 - 1983 study	152.4[a]	962[b]	0.84[c]	1 039[d]	106	0.66	N/A	2.77
- 1984 study	160.1	1 032	0.82	657 (839)[e]	609	2.53	1.08	3.08
First ten years								
- 1983 study (1987-96)	1 467[a]	10 410[b]	0.84	10 799	1 594	1.01	N/A	3.13
- 1984 study (1988-97)	1 538	11 740	0.82	6 943 (9 178)[e]	7 462	3.23	1.38	3.69

a Reflects a slower volume build-up period for the 1983 estimate based on Dome's most recent estimates. In 1990, the difference in CIF revenue is US$ 70 million of which 70% is due to volume and 30% due to price effects. In the ten year period, the CIF revenue difference is US $1 330 of which 40% is due to volume and 60% is due to price effects.

b The lower foreign exchange rate in the 1984 study increases revenue in C$ because FOB revenue is denominated in US$.

c The 1983 total cost includes five LNG tankers and project developer returns on the front end. The unbracketed 1984 estimate includes four LNG tankers and minimum facility costs. The bracketed 1984 estimate includes the project developer's share of Station 3 revenue to indicate total costs before producer gas value is determined.

d Based on ABP set by 65% parity with crude oil in Toronto and reduced by transportation tariffs and COSC.

e

f

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2.4.2 Discussion of Results

Current forecasts of Japanese LNG demand require new supply of LNG by 1990. A significant policy change away from LNG would be required to eliminate the need for new LNG supply. The Western LNG project has a sales agreement to supply incremental Japanese demand at prices competitive with the other supply sources. As in the 1983 study, the Western LNG project is a plausible undertaking in the context of the Japanese market.

The Japanese utility companies involved in the project have extended the project approval date on several occasions due to delays in negotiating satisfactory agreements and approvals in Canada. The most recent extension to 31 October 1984 is widely believed to be the last significant extension. By this date, Dome must have completed project partner and gas supply agreements, all regulatory approvals and its corporate debt restructuring.

The 1984 study shows an increase in project CIF revenue caused by higher volume in the initial years and a change from Montreal imported crude price to average U.S. crude price in computing the Canadian/U.S. border reference price for natural gas. When the higher revenue is combined with lower project costs, due mostly to project restructuring, lower inflation and better cost effectiveness, the residual value of natural gas rises substantially above the 1983 estimate. However, returns to the natural gas producer do not equal the Alberta border price during the first ten years of operation.

The government of British Columbia has approved removal of 50% of the project's gas requirements from the province under certain conditions. The government believes a substantial natural gas surplus will exist even after allocation for domestic and U.S. export gas demand, and is prepared to have a portion of this surplus committed to the Western LNG project. Actual contract terms for British Columbia gas supply are to be negotiated between Dome and individual natural gas producers.

The project does not meet the export gas pricing policy of the Alberta government. Current government policy requires all sales of Alberta gas to ex-Alberta markets to meet or exceed the ABP. The Western LNG project cannot provide sufficient assurance that Alberta gas supply would be priced at or above ABP. The government is reluctant to establish a more flexible pricing policy when the Western LNG project accounts for about 3% of total Alberta gas production and when the other ex-Alberta markets do pay the ABP or more. If more flexible natural gas pricing is expected, it is possible the Alberta government could relax its export price policy.

Alberta is expected to commence price negotiations with other ex-Alberta gas purchasers in the next one to two years. Completion of these negotiations will likely involve a more flexible pricing system, and may recognize values of natural gas at prices below the

ABP calculated on 65% parity with crude oil prices in Toronto. At such a time, the returns from the Western LNG project may be satisfactory.

Natural gas producers in British Columbia have expressed interest in supplying the project, but contract terms, and especially the share of residual gas value going to the producer need to be successfully negotiated.

Natural gas producers in Alberta also have undertaken contract negotiations for gas supply to the Western LNG project. In addition, they may view alternative market opportunities for sales to the U.S. more favourably than British Columbia producers. As the Western LNG project start-up is further delayed, the prospects of better U.S. gas market opportunities increase for Alberta producers.

Discussions with major Alberta gas producers also indicate a reluctance to develop a new gas marketing system (i.e. the Western LNG project) when returns to project partners are equal to or below those from sales to an existing marketing system or other investment opportunities in the oil and gas sector.

The Western LNG project needs additional partners to proceed. The project is too large for the current partners to handle and, with several new financially sound partners, government approvals may be more forthcoming. Negotiations to secure new partners are actively underway and should be complete by September.

3. Natural Gas Liquids (NGL's) Extraction

Since the 1983 study, Westcoast Transmission Company Limited (WTCL) has announced it will build a new deep cut facility to recover NGL's. Facility approval from the government of British Columbia has been applied for, engineering and design have commenced, and project construction is expected to commence in 1984. Capital cost will be about $45 million for a plant with 370 MMCF per day (10,500 10^3m^3 per day) inlet gas capacity, and operations would commence in late 1985. Marketed production will be 3200 barrels per day (b/d) (510 m^3 per day) propane, 1200 b/d (190 m^3 per day) butane and 400 b/d (65 m^3 per day) pentanes plus. A blended NGL stream will be shipped by pipeline from the plant's location at Taylor to a fractionation plant at Kamloops where marketed products will be separated. Pipeline modification and the fractionation plant will cost $20 million.

The new facility is capable of extracting ethane from the gas stream, but no market exists at this time. Petrochemical feedstock demand in British Columbia will not include ethane, and there is currently no economic transportation to large ethane markets at enhanced oil recovery projects in northwest Alberta.

The project's electric energy requirements depend on the use of electric or gas drive for the cooling process. Preliminary indicators are that electric drive will be economic and load will be 20 MW and 150 GW.h per year.

The 1983 study predicted an extraction facility to commence operation in 1987 with a total load of 100 GW.h per year based on inlet gas capacity of 9000 10^3m^3 per day. The new figures noted above for the announced project should now be used.

4. Petrochemicals

4.1 Introduction

Since the 1983 study, there have been no developments which would change the conclusion that ethylane and derivative plants will not be constructed in B. C. during the forecast period. However, developments in natural gas pricing and petrochemical market demand do require updating for methanol and ammonia.

4.2 Methanol

The 1983 study noted that chemical grade methanol market was relatively mature and would be expanded in line with world economic growth except for feedstock demand to produce acetic acid by a more economic process than currently used. Major potential growth exists in fuel uses for methanol.

The situation for 1984 has not changed materially. The fuel uses of methanol have emerged more slowly than widely predicted, and the final role of methanol as a fuel is not clear. Other alternative fuel, such as Natural Gas for Vehicles (NGV) face the same potential and uncertainty.

The underlying factors which could cause large growth for methanol fuel have been given a boost by recent discussion to eliminate use of lead in Canadian and U.S. gasoline. Methanol can be used as a blend with gasoline to achieve octane ratings when lead is removed. Further, continued testing by major automobile manufacturers with engines capable of operating on pure methanol continues, and has reached the stage of major field tests.

Methanol supply remains far in excess of demand, especially in Canada where 1983 demand was about 190 kt compared to capacity of 1900 kt. Even substantial Canadian demand for methanol in gasoline blends would still require significant exports. New production facilities in several countries are now coming on stream and competition for export markets will be substantial in the short and medium term.

In the longer term, Canadian methanol production will become more committed to various markets. The Celanese plant in Edmonton is now producing methanol for the U.S. and offshore markets. Celanese have announced plans to build a new acetic acid plant with methanol feedstock during the late 1980's. The Alberta Gas Chemical Limited (AGCL) project at Medicine Hat, Alberta markets extensively to eastern Canada, eastern and northwestern U.S. and to offshore markets*. As these market patterns and increased Canadian demand develop, a market opportunity for B. C. would occur in the 1990 period. B. C. potential for Pacific Rim market opportunities for methanol are good because it has economic ocean freight while Alberta producers have a substantial land transportation burden.

During 1983, the government of British Columbia announced a new natural gas pricing policy which allows gas producers and petrochemical plant developers to negotiate a market price for natural gas supply. This is a meaningful development for B. C. methanol production because it allows natural gas pricing to be a function of market forces. Whether a suitable price for both producers and developers will be obtained awaits the outcome of negotiations.

Consequently, while market uncertainties remain and excess short and medium term supply will exist, it would be premature to eliminate the B. C. methanol project predicted for 1990 in the 1983 study before natural gas pricing levels are known. As such, a methanol project located on tidewater continues to be forecast for the 1990-1995 period.

As in 1983, modern methanol projects are designed to require little, if any purchased electric energy, and any load associated with this plant would be in B. C. Hydro's general load category. A world scale facility would produce up to 650 kt per year and have a capital cost of $300 to 350 million (1984 $).

4.3 Ammonia

Ammonia markets have rebounded substantially since the 1983 study, especially in the U.S. where ammonia price and volume have increased as the Payment-In-Kind (PIK) program has been phased out.

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* A recent development for AGCL is to take methanol from a new plant in Trinidad to the U.S. East Coast to displace AGCL methanol from Medicine Hat which will now be shipped to Japan to meet the needs of a Japanese company which owns a share of the Trinidad plant.

Ammonia demand in the world will continue to grow at about three percent per year. This is essentially the long term market demand expected in the 1983 study, but with quicker rebound from the low volume in 1982/83 fertilizer year. Prices for ammonia also rebounded faster than implicitly expected in the 1983 study. With modest price increase in agricultural products, the affordable price of ammonia will be limited in the short run to its impact on production volume increases of agricultural products.

Ammonia demand and price factors are, then, similar to the 1983 study. In that study, the economic supply cost from a new B. C. ammonia facility was estimated to be U.S. $350 per tonne (1982 $) which is about double current prices in North American markets. However, with new ammonia demand emerging in the Pacific Basin, a tidewater project in B. C. could be plausible in the early 1990's.

As with methanol a major change in the gas pricing for petrochemical projects has occurred in B. C. Until more is known about the price level which will be negotiated between gas producers and ammonia project developers, it is difficult to assess the impact of the new gas pricing policy on the prospect of new ammonia plant developments.

If an ammonia plant did proceed, it would be world scale capacity of 350 to 400 kt per year of ammonia (and possibly the same production of urea which uses ammonia as a feedstock), and have a capital cost of $400 to 450 million (1984 $). The electric energy requirements for such a facility would be about 5 MW and 35 to 40 GW.h per year.